CALIFORNIA
ENERGY
COMMISSION

2002 MONTHLY ELECTRICITY FORECAST: CALIFORNIA SUPPLY/DEMAND CAPACITY BALANCES FOR JANUARY - SEPTEMBER, 2002

STAFF REPORT

Documentation of Baseline Assumptions and Principal Uncertainites

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Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

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Summary

This outlook responds to a request from Tom Dressler, Consultant for the Joint Legislative Audit Committee. It provides the Energy Commission Staff's current assessment of the statewide baseline physical electricity supply and most likely electricity demand for each month between January and September of 2002. Its purpose is to illustrate whether, if reasonable financial conditions are in place, the existing system and additions in process are sufficient to serve capacity needs under a reasonable set of conditions. The report assumes that stakeholders will reach agreement both on how to pay for past electricity bills and for electricity consumed in 2002. The staff has been working with stakeholders and the California Independent System Operator to refine our baseline assumptions, which are based on the best available data.

In addition to providing the monthly outlook, the report also documents the source of our assumptions. The report includes information on two key demand uncertainties and one supply-side uncertainty. Overall, next year's electricity demand will be heavily influenced by how much of 2001's conservation behaviors carry forward. The range of this uncertainty is included. Similarly, summer peak demand is largely a function of air conditioning, so we include several temperature scenarios. To document supply-side uncertainty, we provide information on different estimates of how much new generation is likely to come on line each month.

Because the report is focused on capacity adequacy, it embodies planning for adverse conditions that might strain the resources of the system. However, it also tries not to be too conservative, because acquiring resources to meet extremely unlikely conditions would result in increased costs and potential environmental impacts.

Table 1 provides the 2002 monthly supply/demand balance forecast for California for January through September. The Energy Commission Staff estimates that, under baseline conditions, sufficient resources will be available to meet statewide peak load and required operating reserves in a very hot summer (1-in-10 probability). Baseline conditions include completed specific construction of new gas-fired and renewable resources. The supply/demand balance forecast does not address the problem of local area reliability issues not discussed in this report that may continue to exist during the forecast period.

The Energy Commission staff will update this report as conditions change.

Table 1
2002- California Electricity Supply - Peak Demand Balance (MW) On First Day Of The Month
Average Temperatures January - April, 1-in-5 in May, 1-in-10 Temperatures June - September

		January	February	March	April	May	June	July	August	September
1	**California Energy Commission 2002 Baseline Forecast (rev. 9/01)**	**37,396**	**36,218**	**36,035**	**37,194**	**41,621**	**48,871**	**54,248**	**54,248**	**54,248**
2	**Operating Reserve**	**2,357**	**2,274**	**2,261**	**2,343**	**2,632**	**3,066**	**3,443**	**3,443**	**3,443**
3	**California Statewide Peak Demand + Operating Reserve**	**39,753**	**38,492**	**38,297**	**39,537**	**44,253**	**51,937**	**57,691**	**57,691**	**57,691**
4	Existing ISO Control Area Resources Thermal	19,408	19,403	19,398	19,393	19,309	19,208	19,213	19,222	19,211
5	ISO Control Area Nuclear	4,342	4,342	4,342	4,342	4,342	4,342	4,342	4,342	4,342
6	ISO Control Area Hydro	11,346	11,384	11,407	11,409	11,426	11,422	11,396	11,372	11,339
7	ISO Muni Non-Hydro Resources	1,462	1,462	1,470	1,470	1,469	1,448	1,448	1,448	1,448
8	Net Imports ISO Control Area	3,729	3,729	3,729	3,729	4,019	5,068	5,068	5,068	5,068
9	Dependable QF Capacity	5,987	6,022	6,074	6,210	6,244	6,351	6,333	6,301	6,242
10	LADWP Control Area Resources	7,964	7,964	7,964	7,964	7,964	8,199	8,199	8,198	8,197
11	Imperial Irrigation District + Other Non ISO Munis	1,191	1,191	1,191	1,191	1,191	1,152	1,152	1,152	1,152
12	2001 Additions On Line (as of 10/31/2001)	2,236	2,236	2,236	2,236	2,236	2,236	2,236	2,236	2,236
13	**Existing Resources and Dependable Imports**	57,665	57,733	57,812	57,944	58,201	59,427	59,387	59,339	59,235
14	Hydro Derate	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(1,500)	(1,500)	(1,500)	(1,500)
15	Estimated Nuclear Off-Line	-	-	-	(1,073)	(1,073)	-	-	-	-
16	Economic Outages	-	-	-	-	-	-	-	-	-
17	SCR Retrofit	(1,395)	(1,064)	(1,064)	(1,389)	(1,389)	(325)	(325)	-	-
18	Estimated Outages	(5,144)	(6,450)	(7,622)	(6,920)	(5,752)	(3,550)	(3,550)	(3,550)	(3,550)
19	**Estimated Forced & Scheduled Outages**	(9,039)	(10,014)	(11,186)	(11,882)	(10,714)	(5,375)	(5,375)	(5,050)	(5,050)
20	**Existing Resources Available to Meet Load**	**48,626**	**47,719**	**46,626**	**46,062**	**47,487**	**54,052**	**54,012**	**54,289**	**54,185**
21	**Resource Surplus/Deficit**	**8,873**	**9,227**	**8,329**	**6,526**	**3,233**	**2,114**	**(3,679)**	**(3,401)**	**(3,505)**
22	**Generation Additions (Summer Dependable MW) 75% Probability**									
23	2001 Additions Expected to Come On Line in Nov and Dec 2001	518	518	518	518	518	518	518	518	518
24	2002 Additions	555	578	643	1,564	1,638	2,936	3,498	3,749	3,749
25	**Total Generation Additions@75% Probability**	**1,073**	**1,096**	**1,161**	**2,082**	**2,156**	**3,454**	**4,016**	**4,267**	**4,267**
26	**Resource Surplus/Deficit**	**9,946**	**10,323**	**9,490**	**8,607**	**5,390**	**5,568**	**337**	**866**	**762**
27	**Demand Responsive Programs**									
28	Ongoing Programs	4	4	4	4	4	4	4	4	4
29	Interruptible/Emergency Programs	1,330	1,330	1,330	1,330	1,330	1,337	1,337	1,337	1,337
30	Existing Voluntary/Emergency Programs	358	358	358	358	358	358	358	358	358
31	**Demand Responsive Program Total**	**1,692**	**1,692**	**1,692**	**1,692**	**1,692**	**1,699**	**1,699**	**1,699**	**1,699**
32	**Resource Surplus/Deficit**	**11,639**	**12,016**	**11,182**	**10,300**	**7,082**	**7,267**	**2,036**	**2,565**	**2,461**
	[3] DWR 2002 Contracts at peak. For informational purposes only:	5,202	5,208	5,117	5,576	5,746	6,451	7,917	7,954	7,953

Documentation

The explanations are linked to summary **Table 1**. For example, the first line of **Table 1** is “California Energy Commission 2002 Baseline Forecast (rev. 9/01).”

Line 1 Peak Demand Forecast

Actual Peaks:

California benefited from a significant decline in peak demand during 2001 that can be attributed to voluntary conservation, demand responsiveness programs and temperature variations. The historic statewide peak demand since 1998 is provided in **Table 2**.

Table 2
Historic Peak Demand (MW)

Year	Statewide Peak Demand
1998	53,119
1999	53,163
2000	52,588
2001	47,820

1998: Includes 1,337 MW of interrupted non-firm load.
2000: Includes 1,710 MW of interrupted non-firm load.
2002: ISO reports 2001 peak of 48,597 MW, however this includes 1,677 MW for Mexico and does not include portions of the LADWP Control Area or small areas in Northern California (approximately 900 MW).

Temperature-related and Consumer Behavior-related Uncertainties:

The California Energy Commission (CEC) forecasts an annual statewide peak demand corresponding to temperature conditions that have a 1-in-2, 1-in-5, 1-in-10 and 1-in-40 probability of occurring. The CEC *California Energy Demand 2002-2012 Forecast* includes three possible demand scenarios for 2002. **Table 3** illustrates the peak demand for each scenario under various temperature conditions.

One major uncertainty in this report involves energy conserving behavior of Californians. It is difficult to determine how many of the actions taken by electricity consumers over the last twelve months will continue into 2002. Monthly peak demand in 2001 was significantly lower than would be expected. Determining the amount of this reduction that was a result of permanent technological improvements as temporary behavioral changes will continue to be a difficult task into the next few years. **Table 3** shows 3 scenarios.

Table 3
2002 Statewide Coincident Peak Demand Forecast Scenarios (Summer MW)

	Low	**Most Likely**	**High**
1-in-2	50,501	51,277	54,255
1-in-5	52,229	53,033	56,113
1-in-10	53,425	**54,248**	57,402
1-in-40	54,629	55,471	58,697

Source: California Energy Demand 2002-2012 Forecast, September 2001

California's summer peak is driven by weather conditions. **Figure 1** illustrates the Weighted Statewide 3-Day Moving Average High Temperatures used in this forecast. Temperatures are recorded for each climate zone in the state. In creating the 3-moving statewide average, the temperature for each climate zone is weighted by the number of air conditioners in the zone.

Figure 1
Ranking of AC Weighted Statewide 3-Day Moving Average High Temperatures

	Year	Average High Temp. (Degrees Fahrenheit)	Probability
1	1991	92.9	**1-in-40 Temp 93.1 degrees or less**
2	1964	93.3	**1-in-20 Temp 93.75 degrees or less**
3	1960	94.2	
4	1963	94.8	**1-in-10 Temp 94.8 degrees or less**
5	1989	94.9	
6	1962	95.1	
7	1968	95.2	
8	1975	95.8	**1-in-5 Temp 96.1 degrees or less**
9	1965	96.4	
10	1959	96.5	
11	1990	96.9	
12	1979	97	
13	1966	97.1	
14	1973	97.2	
15	1986	97.6	
16	1961	97.7	
17	1971	97.9	
18	1974	98	
19	1970	98	
20	1985	98.2	**1-in-2 Temp 98.7 degrees or less**
20	1995	99.2	**1-in-2 Temp 98.7 degrees or more**
19	1977	99.6	
18	1978	99.6	
17	1987	99.7	
16	1982	100	
15	1972	100.1	
14	1969	100.2	
13	1996	100.2	
12	1993	100.2	
11	1980	100.6	
10	1994	100.7	
9	1976	100.9	
8	1992	101.1	**1-in-5 Temp. 101 degrees or more**
7	1967	101.1	
6	1997	101.2	
5	1984	101.4	
4	1983	101.5	**1-in-10 Temp 101.5 degrees or more**
3	1998	101.9	
2	1981	102.2	**1-in-20 Temp 102.15 degrees or more**
1	1988	103.4	**1-in-40 Temp 102.8 degrees or more**

40 year average temp. = 98.5

Monthly demand for non-summer months is estimated based on the monthly historic average percent of annual peak multiplied by the 1-in-2 forecasted peak. Staff used the 1-in-5 condition to account for the historic temperature variability in May and the 1-in-10 temperature condition to forecast demand during summer months.

The supply/demand balance table assigns an equal probability that the peak could occur in July, August, or September. June is based on its historic average percent of annual peak multiplied by the forecasted peak. The historic average percent of peak allocations in **Table 4** is used to calculate the monthly demand in **Table 5**.

Table 4
1993 - 2000 Statewide Monthly Peak Electricity Demand as A Percentage of Annual Peak (MW)

	1993	1994	1995	1996	1997	1998	1999	2000	Average	Percent
January	27,216	25,200	29,444	26,962	27,788	27,078	31,352	32,675	28,464	73%
February	25,024	25,396	28,155	26,571	25,837	26,267	31,218	32,071	27,567	71%
March	24,360	24,754	27,862	25,767	27,289	26,106	30,951	32,340	27,429	70%
April	25,691	25,224	27,700	30,384	26,595	26,804	31,073	33,013	28,311	73%
May	27,741	25,141	30,628	30,110	34,396	24,798	32,716	39,521	30,631	78%
June	33,279	33,616	34,692	33,607	32,472	29,281	40,896	43,447	35,161	90%
July	31,018	32,676	39,567	37,782	33,273	37,489	45,574	43,334	37,589	96%
August	33,436	35,715	39,449	37,790	39,187	39,230	43,925	43,509	39,030	100%
September	32,705	31,955	37,651	34,014	38,462	39,010	40,088	43,069	37,119	95%
October	30,288	26,707	32,784	32,419	31,289	27,564	36,692	35,542	31,661	81%
November	25,794	26,146	29,034	26,979	29,140	27,032	32,599	33,180	28,738	74%
December	26,908	27,357	30,184	27,823	28,403	29,299	34,319	33,672	29,746	76%

Table 5
Monthly Statewide Coincident Peak Electricity Demand Forecast 2002 (MW)

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
Baseline Forecast	37,396	36,217	36,035	37,194	40,243	46,195	49,384	51,277	48,767
Temperature Risk Adjustment					1,378	2,676	2,861	2,971	2,825
Monthly Demand Forecast	**37,396**	**36,217**	**36,035**	**37,194**	**41,621**	**48,871**	**52,245**	**54,248**	**51,592**
Operating Reserve	2,357	2,274	2,261	2,343	2,632	3,066	3,443	3,443	3,443
Peak Demand + Reserves	**39,753**	**38,492**	**38,297**	**39,537**	**44,253**	**51,937**	**57,691**	**57,691**	**57,691**

January through April based on average % of 1-in-2 forecast
May based on average % of 1-in-5 forecast
June based on average % of 1-in-10 forecast
July through September based on 1-in-10 forecast with peak assumed to be possibly in any month

Line 2 Operating Reserves

Required operating reserves are determined using seven percent of the monthly peak load minus firm imports. Firm imports are subtracted because it is assumed they will provide their own reserve.

Lines 4 & 5 Existing ISO Thermal Resources

Existing thermal and nuclear resources are based on installed generation as of October 31, 2001. Resources installed before April 1, 2001 are listed within their respective resource type. Thermal unit capacity is derated to reflect summer operating conditions. The summer derate capacity can range from 90 to 96 percent of nameplate capacity based on the type of unit. Note that some of the thermal resources are sold into the market and may be sold to buyers outside California. The nuclear resources are controlled by California Investor Owned Utilities (IOUs).

Lines 6 & 7 Hydro Dependable Capacity

California's hydropower production system comprises a diverse mix of producers, infrastructure, dispatch policy and geography. California has 4,116 MW of installed hydropower capacity owned by: investor owned utilities (36%), state/federal water projects (27%), municipal utility districts (24%), water districts (7%), irrigation districts (5%) and miscellaneous (1%). [Source: Resources Agency March 29, 2001 filing to FERC in docket EL01-47-000, p. ii] Of this total, 11, 400 MW of dependable capacity is located within the Independent System Operator's control area.

The energy from hydroelectric facilities, other than pumped storage units, is typically broken down into two components: run-of-river and pondage. The run-of-river generation is that amount of energy resulting from non-discretionary water flows that are necessary to meet hourly and daily requirements for downstream habitats, water delivery contracts, and flood control. Generation from the run-of-river portion of a hydroelectric facility is continuous at a relatively fixed output level, which is characteristic of a baseload plant.

Larger dams (high head) have additional storage capacity, or pondage, which allows the operator of the dam to control timing of water releases for electric generation. This flexibility in generation from the pondage portion of a dam gives it the characteristics of both an intermediate load following plant and a peaking plant. This flexibility also allows the pondage portion of a hydroelectric facility to serve both the energy and reliability needs of the system.

Of the 14,116 MW of hydropower capacity in California, 10% is in pumped storage and 62% is from facilities backed by sufficient reservoir storage to allow for operational flexibility. This means that California has a significant ability to shape its hydro production, both as a part of economic operation and in times of peak concern. Under normal operations, units are run within multiple constraints of water management, downstream needs and environmental concerns. Normal operations and energy availability are highly affected by water availability and alternative demands on water use. At peak times, both reliability needs and system operations economics elicit a high use of hydro for a few hours. Thus, we speak of hydro facilities as being "energy-limited" rather than "capacity-limited".

Average hydro conditions are assumed in the resource section of the Supply/Demand Table. A separate line is included in the outages portion of the table to account for lower than average conditions. A detailed analysis of the state's hydro system is included in the discussion on **Hydro Derate**.

Line 8 - CA ISO Control Area Imports

Net imports sum gross imports and gross exports into the control area. These transactions include both firm, long-term controls and short-term commercial trades. Staff computes its estimate of net imports based on firm contracts only. The ISO looks at summary trends, which include firm and shorter-term deals. Their approach is reasonable and produces an additional increment of probable resources. But, since non-firm imports and exports are highly variable, staff chooses to rely only on firm contracts for its estimate.

To calculate ISO net imports, staff evaluated firm contract totals with Bonneville Power Administration (BPA) and out-of-state utilities, out-of-state resources owned by California utilities and entitlements to federal resources such as Hoover. **Tables 6 through 9** provide a detailed description of net firm imports.

Table 6
ISO Dynamically Scheduled Resources (MW)

Palo Verde 1 - 3	
SCE Ownership Portion	597
Four Corners 4 - 5	710
Total	1,307
Hoover	
Metro Water District Ownership Portion	248
SCE Ownership Portion	278
Total	526
Total Firm Dynamically Scheduled Resources	**1,833**

Table 7
Firm Imports and Exports Contracts (MW)

Import Contracts	
SCE Geothermal (MW)	
Imperial Valley	440
Total	**440**
BPA to CA Munis	230
BPA to SCE	500
Deseret G&T To CA Munis	92
Idaho Power to CA Munis	14
PNW Generating Co.(Boardman Coal) to TID	57
PacifiCorp to Redding	50
PacifiCorp to SMUD	100
PacifiCorp NW to SCE Delivered at COB	100
PacifiCorp Utah to SCE Delivered at 4 Crners	100
PacificCorp NW to Wstrn Mid-Pac	7
PacificCorp NW to CDWR	100
Portland Gen. Elec.(Boardman Coal) to SDG&E	75
Puget Sound P&L to PG&E	300
Seattle City Light to NCPA	60
Snohomish to SMUD	36
LADWP to CDWR	77
LADWP toTID	51
Total	**1,949**
Export Contracts	
SCE to Arizona Public Service	(5)
SCE to Tucson Electric Power	(100)
Total Exports	**(105)**

Table 8
CA ISO Municipal Owned Out of State Resources (MW)

Pasadena Palo Verde	10
Riverside Palo Verde	12
Vernon Palo Verde	11
SCE.Other Palo Verde	7
Yuma Cogen	53
Anaheim Hoover	40
Azusa Hoover	4
Banning Hoover	2
Colton Hoover	3
Pasadena Hoover	20
Riverside Hoover	29
Vernon	22
San Juan 3 - 4	273
Intermountain 1 - 2	414
Parker - Metro Water District	51
Total	**951**

Table 9
Summary of Net Firm Imports (MW)

Total Dynamic	1,833
CA ISO Utility Owned Out-of-State Resources	951
Contracts	1,949
SCE Out-of-Control Area QF Geothermal	440
Firm Exports	(105)
Total Net Firm Imports	**5,068**

Line 9 - Dependable QF Capacity

Dependable Qualifying Facility (QF) capacity data is calculated from confidential information received from the IOUs by subpoena. QF resources are contracted to the IOUs and would not be sold out of state. **Table 10** provides the CA ISO Control Area monthly dependable QF capacity used in the Supply/Demand Table. The majority of monthly variation in dependable capacity is found in the small hydro and solar assets. Dependable wind capacity is significantly lower than installed capacity due to daily and seasonal variations in wind patterns. QFs experienced an extraordinary amount of outages between fall 2000 and spring 2001 due to the financial implications of the PG&E bankruptcy and SCE near bankruptcy. Staff does not anticipate these financial outages will occur during 2002.

Table 10
CA ISO Control Area QF Dependable Capacity (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Biomass	731	731	731	731	731	731	731	731	731
Cogen	4,147	4,147	4,147	4,147	4,147	4,158	4,158	4,158	4,158
Geothermal	543	543	543	543	543	543	543	543	543
Hydro	99	131	149	154	162	142	134	118	90
Solar	67	65	95	201	203	315	314	311	291
Wind	400	405	409	434	458	462	452	439	430
Total	5,987	6,022	6,074	6,210	6,244	6,351	6,333	6,301	6,242

Lines 10 & 11 - Municipal Resources

Municipal resource data is based on installed generation as of April 1, 2001. Thermal unit capacity is derated to reflect summer operating conditions. Excess municipal capacity can be sold in the market and may be sold out of state.

Line 12 - 2001 Additions Online

New resources installed after April 1, 2001 and before November 1, 2001 are listed as 2001 Additions Online. A detailed listing is included in **Table 11.**

Table 11
New Additions Online (MW)

Online as of 10/31/01			
Approved CEC Projects	**Capacity**	**Derate**	**Online**
Proctor & Gamble	44	44	4/1/01
Sunrise	320	285	6/27/01
Sutter	540	504	7/2/01
Los Medanos	555	532	7/9/01
		1365	
ISO Peaker			
Harbor Cogen	19.00	19.00	6/14/01
NEO/Chowchilla II	48.60	48.60	6/15/01
Wildflower Larkspur (Tejas- Border)	90.00	90.00	7/13/01
Wildflower Indigo (Tejas- Palm Springs)	90.00	90.00	7/26/01
NEO/Red Bluff	46.80	46.80	8/2/01
Alliance/Drews	40.00	40.00	8/15/01
Wellhead/Fresno Cogen	23.00	23.00	8/16/01
Wildflower Indigo (Tejas- Palm Springs)	45.00	45.00	9/10/01
Alliance/Century	40.00	40.00	9/15/01
CalPeak Enterprise #7	49.50	49.50	9/30/01
CalPeak San Diego Border /Otay Mesa	49.50	49.50	10/27/01
		541.40	
Renewables			
Riverside County Waste Resources, Badlands (LFG)	2.00	2.00	2/15/01
Wheelabrator Shasta Energy Co., Inc., (BIOMASS)	3.80	3.80	2/15/01
Sierra Pacific, Sonora (BIOMASS)	7.50	7.50	2/16/01
Metropolitan Water Dist of Southern California, (SMALL HYDRO)	9.90	9.90	5/23/01
San Diego, Point Loma Wastewater Treatment Power Plant (SM HYDRO)	1.35	1.35	5/24/01
Energy 2001, (LFG)	1.20	1.20	5/30/01
SeaWest WindPower, Inc., Alexander 4 (WIND)	3.60	1.08	9/30/01
SeaWest WindPower, Inc., Alexander 1, 2, and 3 (WIND)	4.90	1.47	9/30/01
SeaWest WindPower, Inc., Phoenix 2, 3, 4, 5 (WIND)	7.70	2.31	9/30/01
SeaWest WindPower, Inc., 16 West – 1 & 2 (WIND)	3.50	1.05	9/30/01
SeaWest WindPower, Inc., Catellus 1, 2, 3, 4, 5 (WIND)	35.00	10.5	9/30/01
SeaWest WindPower, Inc., Catellus 6 (WIND)	1.80	0.54	9/30/01
		42.70	
CEC Peakers			
GWF Power Systems - Hanford Energy Park Peaker	95	85	9/1/01
		85	
Other Summer Projects			
Union Sanitary District (Union City)	1.25	1.25	06/01/01
LADWP- Sun Valley	47	47.0	09/06/01
		48.25	
Restart Biomass			
Sierra Forest Products	7	7	3/6/01
Dinuba	12	12	3/27/01
Primary Power	18	18	4/26/01
Honey Lake	30	30	5/17/01
Madera	25	25	6/1/01
Soledad	13	13	7/19/01
		105	
Rerate Energy Commission Projects			
Proctor & Gamble	9	9	5/30/01
El Segundo	10	10	10/8/01
		19	
Rerate Other Projects			
McClellan (SMUD)	22.00	22.00	3/30/01
Mt. Poso Cogen (Millennium Energy)	2.50	2.50	4/30/01
Rio Bravo Jasmin	3.00	3.00	5/1/01
Rio Bravo Poso Unit 1	3.00	3.00	5/1/01
		30.50	
2001 Generation Online as of 10/31/01		**2236**	

Line 14 - Hydro Derate

The Energy Commission counts 11,300 – 11,400 MW of dependable hydro capacity within the ISO's control area, by which we have meant the maximum that could be called upon in a peak or reliability condition. This was not derated last year for low water conditions, because, in contrast to the Northwest, California's reservoirs have been at near normal conditions. However, the ISO has alerted us that they are recording both lower levels of normal operations (which are to be expected) and lower levels of availability at peak moments. This suggested that hydro facilities are, in fact, operating at lower levels.

Staff obtained confidential ISO EMS hydro data for February – May 2001 for the purposes of benchmarking this capacity accounting. The ISO confidential data is summarized below. Throwing out the top two observations as outliers that might represent data errors or unusual conditions, we used as the third highest output observation as an estimate of maximum output in the month. We then examined the fall off for the highest 1 percent of hours, the highest 2%, 5% and 10%. For dependable capacity estimates, we are interested in the highest 1% of hours, because that is what was available during peak usage. But, we were also interested in understanding how quickly the production curve falls off, which is why the top 2%, 5%, and 10% numbers were calculated. Because the energy source of spinning reserves is not collected in a convenient format by the ISO, we looked at three different levels of how much of total spinning reserve came from hydro – 50%, 75% and 90%. These levels were based both on general observation and on spot checks of specific hours. We found that May, typically the highest hydro production month, produced between 11,700 MW and 12,061 MW in peak operations, with normal operations dropping off to 8,500 – 9,000 MW.

Table 12
ISO Control Area _ Hourly Hydro & Reserves Data for February –May 2001

Energy & Spin	3rd Highest Observation	.1%	2%	5%	10%
February					
50% spin	6,320	5,989	5,728	5,327	4,896
75% spin	6,674	6,261	6,121	5,717	5,238
90% spin	6,959	6,525	6,345	5,970	5,455
March					
50% spin	6,413	5,924	5,764	5,470	4,984
75% spin	6,699	6,226	6,042	5,748	5,289
90% spin	6,954	6,415	6,210	5,905	5,475
April					
50% spin	7,159	6,509	6,180	5,719	5,393
75% spin	7,440	6,772	6,465	6,007	5,698
90% spin	7,609	6,939	6,646	6,161	5,886
May					
50% spin	11,707	8,673	8,280	7,861	7,379
75% spin	11,919	9,022	8,593	8,156	7,661
90% spin	12,061	9,232	8,804	8,333	7,842

The ISO lists its control area dependable capacity at 11,800 MW. This 2001 data verifies that they do have that much capacity which can be made available, and that the system typically operates at a lower range of around 8,500 MW in peak May hours and 16,200 MW in winter peak hours**.**

We examined confidential data obtained from some utilities, and consulted hydro facility managers throughout the state to update our hydro capacity estimate. We also examined data submitted in past cases at the CPUC for additional information on seasonal capacity operations. Finally, we queried hydro system managers on how much additional capacity could be furnished in 2002 for short-term reliability needs.

On a system-by-system basis, we examined historic and system manager estimates data for PG&E, Helms pumped storage, SCE, US Bureau of Reclamation, Sacramento Municipal Utility District, the irrigation districts within the ISO control area, and Department of Water Resources. This led to a proposed derate for normal operations of 2,500 MW from our base of 11,400 MW.

The estimate of how much generation can be available in peak moments is based on observation and conversations with facilities managers. The range of estimates was 1,000 – 1,500 MWs. We chose 1,000 MWs for our 2002 estimate. The hydro derate is then: 2,500 MW for normal operations plus 1,000 MW which can be called upon, for a total derate of 1,500 MW.

Lines 15 - 19 Outages

The current outlook for outages during the winter and spring of 2002 assumes a range between approximately 7,000 and 9,500 MW, which includes estimates for shutdowns due to Selective Catalytic Reduction (SCR) retrofit, planned outages for maintenance and nuclear refueling. Actual plant outages between January - April of 2001 ranged between 10,000 to 15,000 MW. Staff is not expecting a repeat of last year's winter high outage levels for the following reasons:

- The FERC June Order on price mitigation is designed to prevent withholding by requiring generators to offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run.

- Increased diligence in coordination of outages by the ISO.

- The outages during the winter and spring of 2001 gave generators the opportunity to conduct extensive maintenance and repairs that had been deferred and install SCR for controlling emissions.

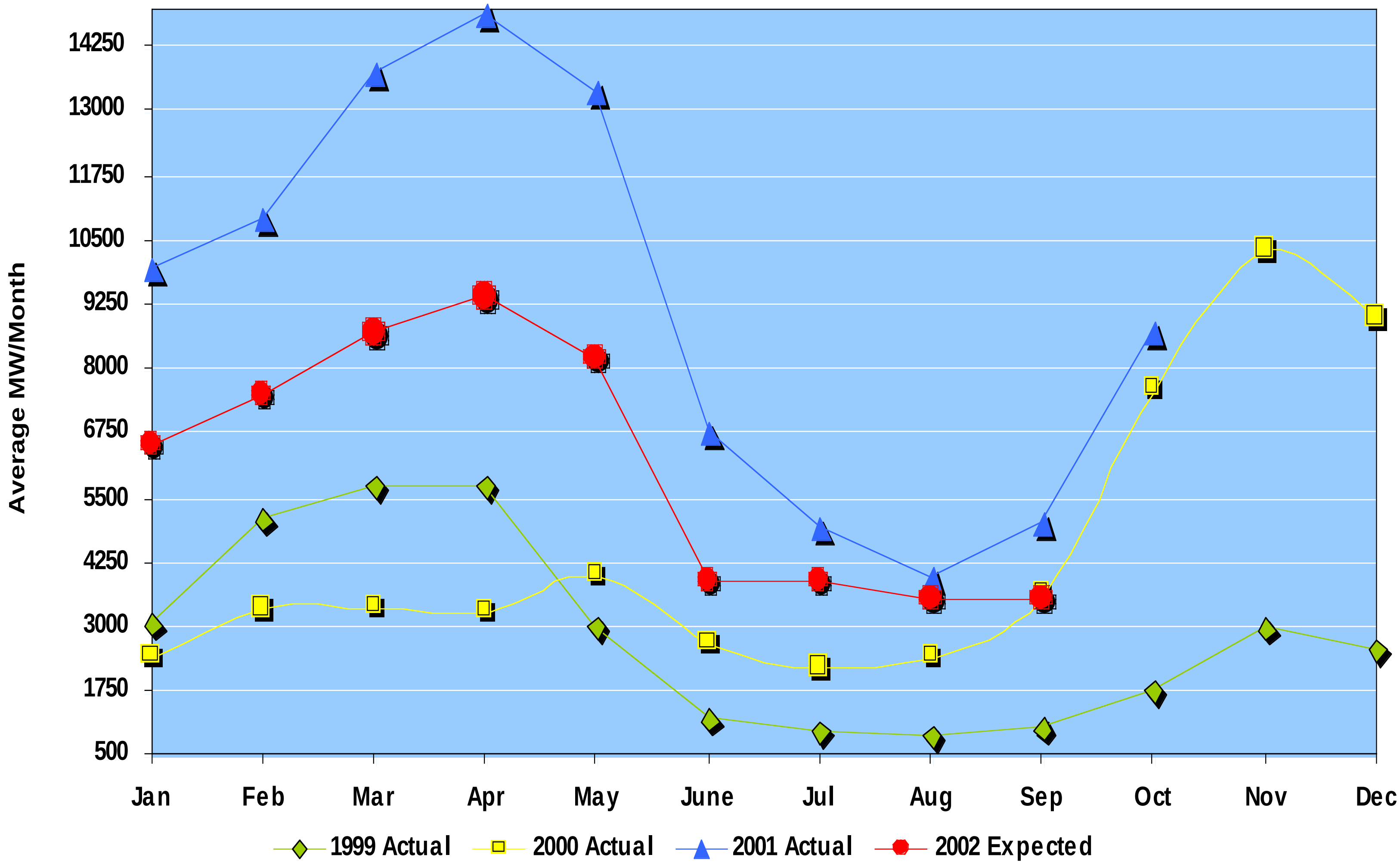
- The power plants in California did not run as hard this summer compared to the summer of 2000.

A line is included for economic outages (line 19), however there are no estimates. The CA ISO gives permission for these outages after assessing the likely need for these slow start units. Staff assumed during periods of peak demand, the CA ISO would not approve any economic outages.

The CA ISO provided outage data through May from their working forecast on 11/14/2001. This data shows the CEC and the CA ISO forecast very similar outage numbers for April and May, but the CA ISO outage number is as much as 3,000 MW higher in January and February. There is sufficient supply adequacy that with a 3,000 MW increase in outages the state will still have the resources needed to meet load. The wide discrepancy between the two forecasts for January and February reiterates the need for better data sharing between the two agencies.

Figure 2 compares January 1999 through October 2001 statewide historical monthly average outages as well as 2002 forecast outages. Hydro derate is not included as an outage in this chart.

Figure 2
Historical and 2002 Expected Statewide Monthly Average Outages (MW)



Lines 23 - 25 New Generation Additions

New generation capacity is forecast to increase by 4,267 MW between November 2001 and September 2002. The majority of this new generation capacity (2,866 MW) will be in the form of new combined cycle power plants. An additional 715 MW will come from new peaker units and co-generation facilities. The remaining additional capacity is from renewable programs and restarting existing facilities.

A detailed listing of all facilities staff considered having a 75% probability of meeting their projected online dates is included in **Tables 13 & 14**.

Table 13
New Additions Expected Online in November and December 2001 (MW)

Online by Dec 1, 2001			
	Capacity	**Derate**	**Online**
ISO Peaker			
Wellhead/Panoche- Los Banos	49.00	49.00	11/30/01
CalPeak Fresno/Panoche	49.30	49.30	11/30/01
Wellhead/Gates (Huron)	45.40	45.40	11/30/01
		143.70	
Renewables			
November Renewables		5.47	11/15/01
December Renewables		21.81	12/1/01
		27.28	
CEC Peakers			
Calpine Gilroy Phase 1	135	120	11/30/01
		120	
LADWP			
LADWP Harbor	235	209	11/20/01
		209	
Restart Biomass			
Jackson Valley	18	18	11/16/01
		18	
2001 Generation Online By 12/1/01		**518**	

Table 14
New Additions Expected Online by September 1, 2002 (MW)

Project		Capacity	Derate	Online
	Online in 2002			
Misc. Renewable Projects		78.55	27.41	1/1/02
Calpine King City		50	45	12/28/01
Huntington Beach		450	450	12/30/01
Energy Transfer/Hanover		23	23	12/31/01
El Segundo		10	10	1/1/02
	Online By 1/1/02		**555**	
Misc. Renewable Projects		30	22.5	1/31/02
	Online By 2/1/02		**22.5**	
CalPeak/El Cajon		49.50	49.50	2/15/02
El Segundo		8	8	3/1/02
Misc. Renewable Projects		13.85	8.68	3/1/02
	Online By 3/1/02		**66**	
Delta - Calpine		880	844	4/1/02
COSO Navy 2		12	12	4/1/02
Redding		54	54	4/1/02
Misc. Renewable Projects		48.55	11	4/1/02
	Online By 4/1/02		**921**	
Valero Refining - Valero Cogeneration I		51	45	4/30/02
Misc. Renewable Projects		126.97	30	4/15/02
	Online By 5/1/02		**75**	
La Paloma I		262	251	5/13/01
Moss Landing - Duke		1,060	1,017	6/1/02
Misc. Renewable Projects		79.85	29.49	6/1/02
	Online By 6/1/02		**1,297**	
La Paloma II		262	251	6/9/01
CalPeak/Vaca-Dixon		49.00	49	6/30/02
La Paloma III		262	251	7/1/01
Misc. Renewable Projects		48.00	10.75	7/1/01
	Online By 7/1/02		**562**	
La Paloma IV		262	251	7/22/01
	Online By 8/1/02		**251**	
	Online By 9/1/02		**0**	
Online By September 2002			**3,749**	

There are three possible generation addition scenarios that staff considered for its forecast. A summary of these scenarios is provided in **Table 15.** The most conservative scenario was chosen for planning purposes. This 75% scenario does not include any of the new peaker plants that have signed a Letter of Intent (LOI) with the California Consumer Power and Conservation Financing Authority (CPA). When these LOIs become CPA contracts and the peakers receive financing, these units will be included in the Supply/Demand Balance.

Table 15
New Generation Scenarios

Probability	Online By August 1 (MW)
75%	4,267
50%	4,427
All Possible	5,261

Lines 27 - 31 Demand-Response Programs (DRP)

The 2002 DRP assumptions that staff used in the forecast are included in **Table 16**. Several DRPs are still in the early stages of implementation and their total impact may not be fully realized in the Supply/Demand Balance. Some of these programs are CEC proposed modifications to the curtailable programs, new public awareness programs, new legislation and new 20/20 programs.

2002 Demand Table 16
Responsiveness Programs (MW)

		January	February	March	April	May	June	July	August	September
	Ongoing Programs									
	Scheduled Load Reduction Program	4	4	4	4	4	4	4	4	4
	Discretionary Load Curtailment Program	0	0	0	0	0	0	0	0	0
28	**Ongoing Subtotal**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**	**4**
	Interruptible/Emergency Programs									
	Demand Bidding Program	33	33	33	33	33	33	33	33	33
	Existing Interruptible Program	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147	1,147
	Base Interruptible Program	2	2	2	2	2	2	2	2	2
	Ag Pumping	42	42	42	42	42	42	42	42	42
	AC Cycling						7	7	7	7
	Optional Binding Mandatory Curtailment	107	107	107	107	107	107	107	107	107
29	**Interruptible/Emergency Programs Total**	**1,330**	**1,330**	**1,330**	**1,330**	**1,330**	**1,337**	**1,337**	**1,337**	**1,337**
	Existing Voluntary/Emergency Programs									
	State Building Demand Response	150	150	150	150	150	150	150	150	150
	Federal and Local Demand Reduction	208	208	208	208	208	208	208	208	208
30	**Existing Voluntary/Emergency Programs Total**	**358**	**358**	**358**	**358**	**358**	**358**	**358**	**358**	**358**
31	**Total Additional Demand Reduction Impacts**	**1,692**	**1,692**	**1,692**	**1,692**	**1,692**	**1,699**	**1,699**	**1,699**	**1,699**